PA 1143663

REC'D 22 APR 2004

THE UNITED STATES OF AMERICA

TO ALL TO WHOM THESE PRESENTS SHALL COME:

UNITED STATES DEPARTMENT OF COMMERCE

United States Patent and Trademark Office

March 12, 2004

THIS IS TO CERTIFY THAT ANNEXED HERETO IS A TRUE COPY FROM THE RECORDS OF THE UNITED STATES PATENT AND TRADEMARK OFFICE OF THOSE PAPERS OF THE BELOW IDENTIFIED PATENT APPLICATION THAT MET THE REQUIREMENTS TO BE GRANTED A FILING DATE UNDER 35 USC 111.

APPLICATION NUMBER: *60/458,867*
FILING DATE: *March 28, 2003*

PRIORITY DOCUMENT
SUBMITTED OR TRANSMITTED IN COMPLIANCE WITH RULE 17.1(a) OR (b)

By Authority of the
COMMISSIONER OF PATENTS AND TRADEMARKS

M. K. HAWKINS
Certifying Officer

03-31-03 60458867 .032803 A/Prov

J1060 U.S. PTO
03/28/03

PTO/SB/16 (6-95)
Approved for use through 04/11/98. OMB 0651-0037
Patent and Trademark Office; U.S. DEPARTMENT OF COMMERCE

PROVISIONAL APPLICATION COVER SHEET

This is a request for filing a PROVISIONAL APPLICATION under 37 CFR 1.53 (b)(2).

Docket Number	101.0146	Type a plus sign (+) inside this box -->	+

J1011 U.S. PTO
60/458857

INVENTOR(s)/APPLICANT(s)

LAST NAME	FIRST NAME	MIDDLE INITIAL	RESIDENCE (CITY AND EITHER STATE OR FOREIGN COUNTRY)
BROWN	GEORGE	A.	Oak House, 12 Woodlands Dr., Beaconsfield, Buckinghamshire, HP9 1JY, UK

TITLE OF THE INVENTION (280 characters max)

Method and System to Measure Injector Inflow Profiles

CORRESPONDENCE ADDRESS

Patent Counsel, Schlumberger Technology Corporation,
P.O. Box 1590, Rosharon

STATE	Texas	ZIP CODE	77583-1590	COUNTRY	U.S.A.

ENCLOSED APPLICATION PARTS *(check all that apply)*

[X]	Specification	*Number of Pages*	9	[ ]	Small Entity Statement
[X]	Drawing(s)	*Number of Sheets*	2	[ ]	Other (specify)

METHOD OF PAYMENT *(check one)*

[ ] A check or money order is enclosed to cover the Provisional filing fees

[X] The Commissioner is hereby authorized to charge filing fees and credit Deposit Account Number: 50 2475

PROVISIONAL FILING FEE AMOUNT ($): $160.00

Schlumberger Private

The invention was made by an agency of the United States Government or under a contract with an agency of the United States Government.

[X] No.

[ ] Yes, the name of the U.S. Government agency and the Government contract number are: ______

Respectfully submitted,

SIGNATURE ______ Date 3/28/2003

TYPED or PRINTED NAME Jeffrey E. Griffin

REGISTRATION NO. *(if appropriate)* 36,534

[ ] Additional inventors are being named on separately numbered sheets attached hereto

PROVISIONAL APPLICATION FILING ONLY

IN THE UNITED STATES PATENT & TRADEMARK OFFICE

Applicant: George A. Brown | Attorney Docket No: 101.0146 PSP
Serial No: | Art Unit:
Filed: | Examiner:
For: **Method and System to Measure Injector Inflow Profiles**

Box Provisional Patent Application
Assistant Commissioner for Patents
Washington, DC 20231

CERTIFICATE OF MAILING

I hereby certify that Provisional Application Cover Sheet is being deposited with the United States Postal Service as Express Mail No. EV 104 891 172 US in an envelope addressed to: Assistant Commissioner for Patents, Washington, D.C. 20231.

Joanne Hyland　　3/28/03
Date

Joanne C. Hyland
Schlumberger Technology Corporation
14910 Airline Road
Rosharon, Texas 77583-1590

(101.0146)

METHOD AND SYSTEM TO MEASURE INJECTOR INFLOW PROFILES

BACKGROUND

The invention generally relates to a method and system for use in subterranean wellbores. More particularly, the invention relates to such a system and method used to measure inflow profiles in subterranean injector wellbores.

It is important for an operator of a subterranean injector wellbore, such as an oil or gas well, to determine the inflow profile of the wellbore in order to analyze whether all or just certain parts of a specific zone are injecting fluids therethrough. This determination and analysis is specially important in horizontal wellbores. In horizontal wellbores, the amount of fluid flowing through a specific zone tends to decrease from the heel to the toe of the well. Often, the toe and sections close to the toe have very little and sometimes no fluid flowing therethrough. An operator with knowledge of the inflow profile of a well can then attempt to take remediation measures to ensure that a more even inflow profile is created from the heel to the toe of the well.

Thus, there exists a continuing need for an arrangement and/or technique that addresses one or more of the problems that are stated above.

SUMMARY

The invention comprises a method of determining the inflow profile of an injection wellbore, comprising stopping injection of fluid into a formation, the formation intersected by a wellbore and the wellbore having an area located before the formation; monitoring temperature at least partially across the wellbore and formation; injecting fluid into the formation once the temperature in the area increases; and monitoring the movement of the increased

temperature as it flows from the area along the formation. The monitoring can be performed using a distributed temperature system.

BRIEF DESCRIPTION OF THE DRAWING

Fig. 1 is a schematic of a wellbore utilizing the present invention.

Fig. 2 is a plot of a geothermal temperature profile of a horizontal wellbore.

Fig. 3 is a plot showing temperature profiles taken along a wellbore at different points in time, including during injection and while the well is shut-in.

Fig. 4 is a plot illustrating the movement of a temperature peak along the wellbore and relevant formation.

Fig. 5 is a plot of the velocity of the peak of Fig. 4 as it moves along the wellbore and relevant formation.

DETAILED DESCRIPTION

Figure 1 is a general schematic of the present invention. A tubing 10 is disposed within a wellbore 12 that may be cased or uncased. Wellbore 12 can be a horizontal or inclined well that has a heel 14 and a toe 16. The horizontal section may have a liner, may be open-hole, or may have a continuation of tubing 10. Wellbore 12 intersects a formation 18 such as a hydrocarbon formation. A packer 11 may be disposed around the tubing 10 to sealingly separate the wellbore area above and below the packer 11.

Wellbore 12 is an injector wellbore and the tubing 10 thus has injection equipment 20 (such as a pump) connected thereto near the earth surface 22. Injection equipment 20 may be connected to a tank 23 that has the fluid which is to be injected into formation 18. Typically, the fluid is injected by the injection equipment 20 through the tubing 10 and into formation 18.

Tubing 10 can have ports (not shown) adjacent formation 18 so as to allow the flow of the fluid into formation 18. In other embodiments, a liner with slots disposed in the horizontal section may provide the fluid communication, or the horizontal section may be open hole. Perforations (not shown) may be made along formation 18 to facilitate fluid flow into the formation 18.

A distributed temperature measurement system 24 is also disposed in the wellbore 12. The system 24 includes an optical fiber 26 and an optical launch and acquisition unit 28.

In the embodiment shown, the optical fiber 26 is disposed along the tubing 10 and is attached thereto on the outside of the tubing 10. In other embodiments, the optical fiber 26 can be disposed within the tubing 10 or outside of the casing of the wellbore (if the wellbore is cased). The optical fiber extends through the packer 11 and across formation 18. The optical fiber 26 may be deployed within a conduit, such as a metal control line. The control line is then attached to the tubing 10 or behind the casing. The optical fiber 26 may be pumped into the control line by use of fluid drag before or after the control line and tubing 10 are deployed downhole. This pumping technique is described in U.S. Reissue Patent No. 37,283.

The unit 28 launches optical pulses through the optical fiber 26 and then receives the return signals and interprets such signals to provide a distributed temperature measurement profile along the length of the optical fiber 26. In one embodiment, the system 24 is an optical time domain reflectometry (OTDR) system which also includes the unit 28 with a light source and a computer or logic device. OTDR systems are known in the prior art, such as those described in U.S. Pat. Nos. 4,823,166 and 5,592,282 issued to Hartog, both of which are incorporated herein by reference. In OTDR, a pulse of optical energy is launched into an optical fiber and the backscattered optical energy returning from the fiber is observed as a function of time, which is proportional to distance along the fiber from which the backscattered light is

received. This backscattered light includes the Rayleigh, Brillouin, and Raman spectrums. The Raman spectrum is the most temperature sensitive with the intensity of the spectrum varying with temperature, although Brillouin scattering and in certain cases Rayleigh scattering are temperature sensitive.

Generally, in one embodiment, pulses of light at a fixed wavelength are transmitted from the light source in unit 28 down the optical fiber 26. At every measurement point in the optical fiber 26, light is back-scattered and returns to the unit 28. Knowing the speed of light and the moment of arrival of the return signal enables its point of origin along the optical fiber 26 to be determined. Temperature stimulates the energy levels of molecules of the silica and of other index-modifying additives – such as germania – present in the optical fiber 26. The back-scattered light contains upshifted and downshifted wavebands (such as the Stokes Raman and Anti-Stokes Raman portions of the back-scattered spectrum) which can be analyzed to determine the temperature at origin. In this way the temperature of each of the responding measurement points in the optical fiber 26 can be calculated by the unit 28, providing a complete temperature profile along the length of the optical fiber 26. In one embodiment, the optical fiber 26 is disposed in a u-shape along the wellbore 12 providing greater resolution to the temperature measurement.

Figure 2 shows a graph of the geothermal temperature profile 29 of a generic horizontal wellbore. This profile shows at 30 a gradual increase in temperature (T) as the depth (D) of the well increases, until at 32 a stable temperature is reached along the horizontal section of the wellbore. The geothermal temperature profile is the temperature profile existing in the wellbore without external factors (such as injection). After injection or other external factors end, the wellbore will gradually change in temperature towards the geothermal temperature profile.

In one embodiment of this invention, in order to determine the inflow profile of a wellbore 12, the wellbore 12 must first be shut in so that no injection takes place. The temperature profile of the wellbore 12 changes if there is injection and throughout the shut in period. Figure 3 shows these changes.

Curve 34 is the temperature profile of the wellbore 12 during injection, wherein the temperature is relatively stable since the injected fluid is flowing through the tubing 10 and into the formation 18.

Curve 36 represents a temperature profile of the wellbore 12 taken after injection is stopped and the well is shut-in. Curve 36 is already gradually moving towards the geothermal profile 29. However, section 40 of curve 36 is changing at a much slower rate than the early part of the curve 36 because section 40 represents the area of the formation 18 which absorbed the most fluid during the injection step. Therefore, since this area is in contact with a substantial amount of fluid already injected in the formation 18, this area takes a longer time to heat or return to its geothermal norm. Of interest, peak 42 is present on curve 36 because peak 42 is the area of wellbore 12 found directly before formation 18 (and not taking fluids); therefore, a substantial temperature difference exists between peak 42 and section 40.

Curve 38 represents a temperature profile of the wellbore 12 taken subsequent to the temperature profile represented by curve 36. Curve 38 shows that the temperature profile is still heating towards the geothermal norm, but that the difference between peak 44 (peak 42 later on in time) and the section 40 are still apparent.

The object of this invention is to determine the velocity of the fluid being injected across the length of the formation 18 in order to then determine the inflow profile of such formation 18. The technique used to achieve this is to re-initiate injection after a relatively short shut-in period

and track the movement of the peak (42, 44) by use of the distributed temperature measurement system 24.

Figure 4 shows four curves representing temperature profiles taken over time: curve 50 is a profile taken during shut-in, curve 52 is a profile taken after injection is re-started, curve 54 is a profile taken after curve 52, and curve 56 is a profile taken after curve 54. For purposes of clarity, the entire temperature profile of the wellbore has not been shown. Curve 50 includes a temperature peak 58A that represents the temperature peak present during shut-in and found directly before formation 18 (corresponds to peaks 42, 44 of Figure 3). Once injection is restarted, the slug of heated fluid represented by peak 58 is essentially "pushed" down the wellbore 12 as is shown by the peaks 58B-D in time lapse curves 52-56. The peak 58A-D, as expected, decreases in temperature in time once injection is restarted.

By tracking the movement of the peak 58A-D down the wellbore 12 (through use of the distributed temperature system 24), an operator may determine the velocity of the peak 58A-D as it moves down the wellbore 12 and the formation 18 in time. As shown in Figure 5, the velocity (V) of the peak 58A-D is then plotted against depth across the length of the formation 18. This plot shows a constant velocity at 60 immediately prior to reaching the formation 18, a gradual decrease of velocity at 62 as the peak moves away from the beginning of the formation 18, and a very low and perhaps non-existent velocity as the peak nears the end of the formation 18. From this plot, one can determine that the latter portion of the formation 18 (that closer to the toe 16) is not receiving much fluid during injection in comparison to the first portion of the formation 18. With this information, one can provide injection inflow profiles across the formation 18, which profiles can be shown in percentage form (percentage of fluid being injected along the length of the formation 18) or quantitative form (with the knowledge of the actual surface injection rate).

Thus, by monitoring the velocity of a heated slug (peaks 58A-D) across a formation 18, the injection inflow profile of a wellbore 12 across a formation 18 can be determined.

Of importance, the shut-in period required to use the present technique is short in relation to the shut-in periods in some comparable prior art techniques. In some prior art techniques, the area of the formation 18 (see section 40) and not the area directly before the formation 18 (see peaks 42, 44) is monitored during the warm back period (and not the injection period) to determine the inflow profile. However, in wellbores that have been injecting for a lengthy period of time, the area of the formation 18 (see section 40) must be monitored for a substantial period of time before the warm back curves begin to move towards the geothermal gradient and the relevant information can be extracted therefrom. With the present technique, the warm back period can be as short as 24-48 hours since the peaks 42, 44 (used as previously stated) begin to shift towards the geothermal profile much more quickly. Thus, a process that would take weeks or months to complete using the prior art techniques can now be complete in several days using the present technique.

While the invention has been disclosed with respect to a limited number of embodiments, those skilled in the art, having the benefit of this disclosure, will appreciate numerous modifications and variations therefrom. It is intended that the appended claims cover all such modifications and variations as fall within the true spirit and scope of the invention.

CLAIMS

What is claimed is:

1. A method of determining the inflow profile of an injection wellbore, comprising:

stopping injection of fluid into a formation, the formation intersected by a wellbore and the wellbore having an area located before the formation;

monitoring temperature at least partially across the wellbore and formation;

injecting fluid into the formation once the temperature in the area increases; and

monitoring the movement of the increased temperature as it flows from the area along the formation.

METHOD AND SYSTEM TO MEASURE INJECTOR INFLOW PROFILES

ABSTRACT OF THE DISCLOSURE

A method of determining the inflow profile of an injection wellbore, comprising stopping injection of fluid into a formation, the formation intersected by a wellbore and the wellbore having an area located before the formation; monitoring temperature at least partially across the wellbore and formation; injecting fluid into the formation once the temperature in the area increases; and monitoring the movement of the increased temperature as it flows from the area along the formation. The monitoring can be performed using a distributed temperature system.

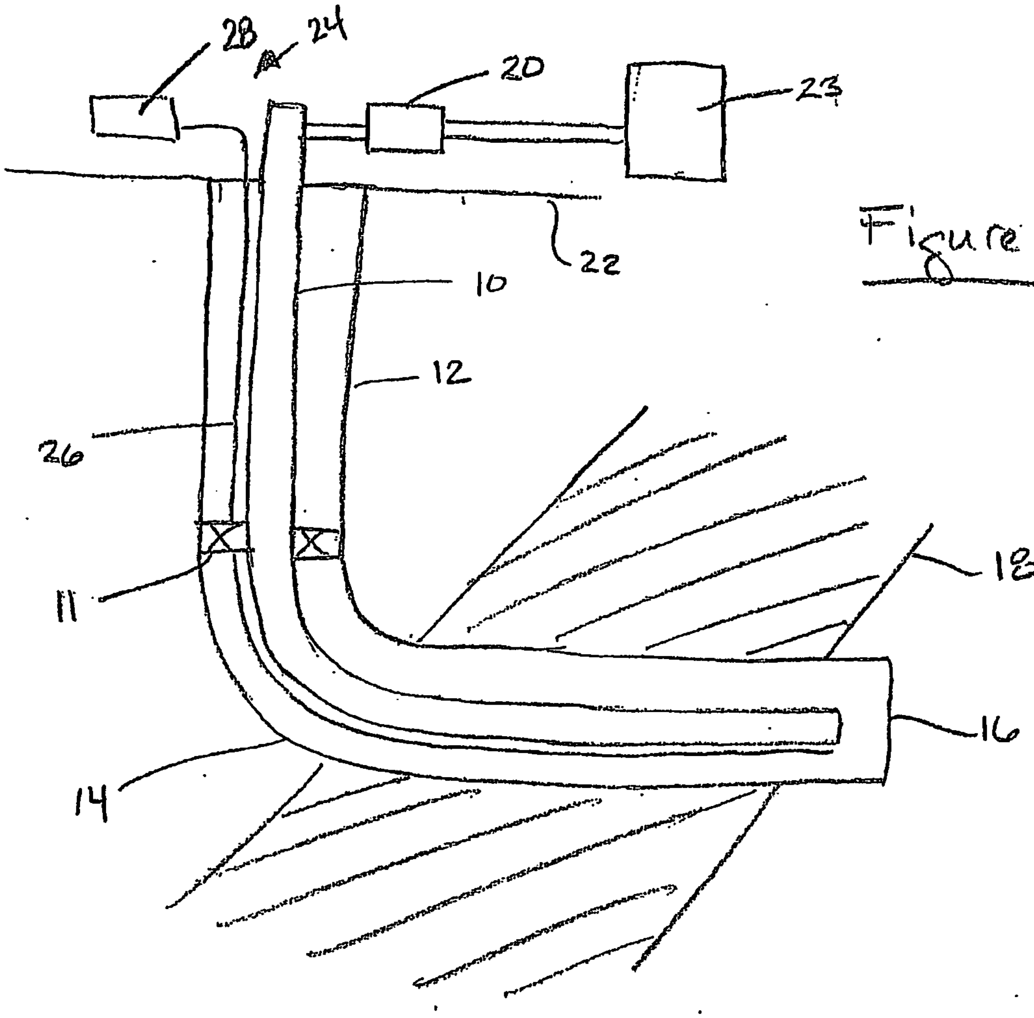

Figure 1

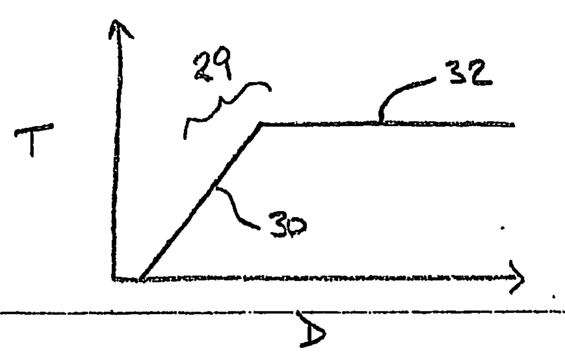

Figure 2

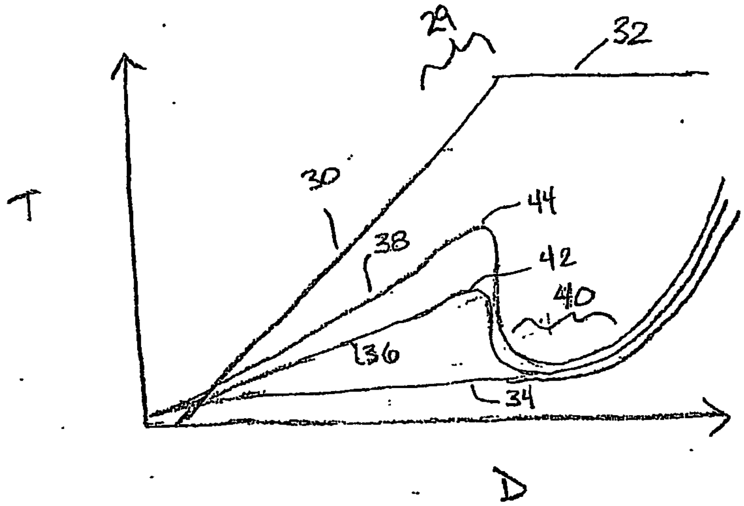

Figure 3

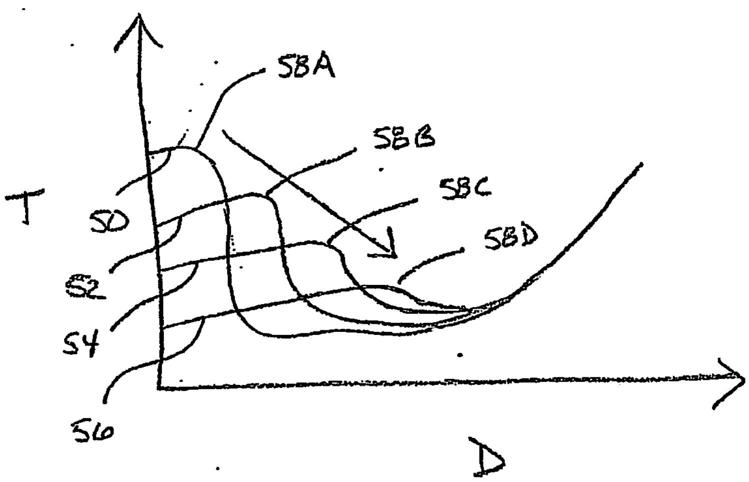

Figure 4

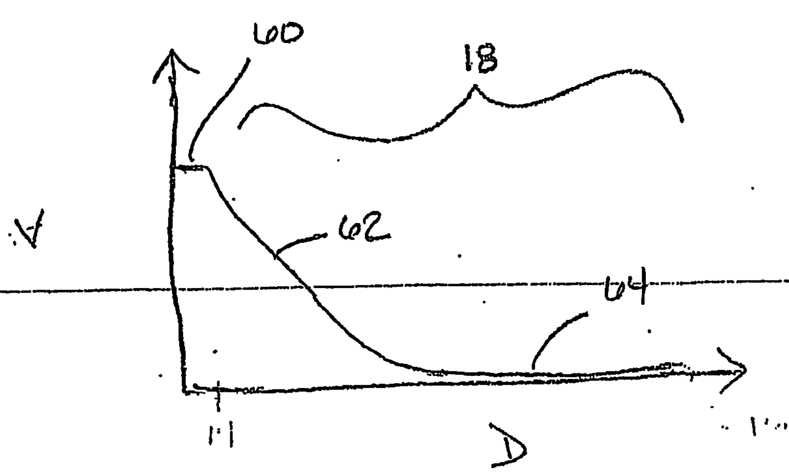

Figure 5